Evaluation of Flexibility Markets for Retailer-DSO-TSO Coordination

Journal:	*IEEE Transactions on Power Systems*
Manuscript ID	TPWRS-00472-2018.R1
Manuscript Type:	Transactions
Date Submitted by the Author:	29-Jul-2018
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Technical Topic Area :	Power system economics, Power system markets
Key Words:	Power system economics, Power distribution, Design methodology, Multilevel systems

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Evaluation of Flexibility Markets for Retailer-DSO-TSO Coordination

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***Abstract*—The rise of Distributed Energy Resources (DERs) can enhance the efficiency of system operations by providing flexibility services to the different agents involved, but they also pose a major resource allocation problem. This study considers three different agents procuring DER services: Distribution System Operators (DSOs) for local congestion management, Transmission System Operators (TSOs) for system-wide reserve deployment, and Retailers for hedging against network usage tariffs based upon peak-load pricing. A variety of market mechanisms are identified to co-ordinate these needs, and three schemes are developed in detail. These are (a) separate markets for each agent, (b) co-ordinated Shapley value allocations for TSO and DSO, and (c) a co-ordinated mechanism including Retailers. These designs are evaluated on a realistic distribution network in Britain for two operational days. The results show a more efficient dispatch from the TSO-DSO co-ordinated procurement over independent sequential procurements. However, the inclusion of Retailers in the joint dispatch is surprisingly less attractive due to the lack of improvement in social welfare, and the undesirable impacts on the DSO.**

***Index Terms*—Distributed Energy Resources, Flexibility Market, TSO-DSO Co-ordination**

NOMENCLATURE

Sets and parameters appear in italics, while variables appear unformatted.

A. Indices

u	Index of flexibility turn up units (demand increase/generation decrease)
d	Index of flexibility turn down units (demand decrease/generation increase)
g	Index of generation units
j	Index of demand units
n/m	Index of nodes
l	Index of line going from node n to node m
tr	Index of transformers
t	Time index of settlement periods within a day

B. Sets

T^{RD}	Set of negative reserves activation time frames
T^{TW}	Set of triad window time frames

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C. Parameters

$F_{un}^{UP,max}$	Upper limit of flexibility turn up unit u (MW)
$F_{dn}^{DW,max}$	Lower limit of flexibility turn down unit d (MW)
P_{in}^{G}	Power produced by generation unit i (MW)
P_{jn}^{D}	Power consumed by demand unit j (MW)
π_{un}^{UP}	Bid of flexibility turn up unit u (£/MWh)
π_{dn}^{DW}	Bid of flexibility turn down unit d (£/MWh)
π^{RD}	Activation price of down reserves (£/MWh)
$VOLL$	Value of Lost Load (£/MWh)
$VOLG$	Value of Lost Generation (£/MWh)
$\hat{P}^{T}$	Probability of triad event
$\hat{C}^{TNUoS}$	Network tariff expected price (£/MW)
B_l	Susceptance of line l
TC_{tr}	Transformer tr rated capacity (MW)
LC_l	Line l rated capacity (MW)
C^{TR}	Transformer cost (£/MW)
C^{L}	Line cost (£/MW/km)
x^{L}	Line reinforcement block size (MW/km)
x^{TR}	Transformer reinforcement block size (MW)

D. Continuous Variables

θ_n	Voltage angle in node n
F_{un}^{UP}	Flexibility activated by turn up unit u (MW)
F_{dn}^{DW}	Flexibility activated by a turn down unit d (MW)
P_{jn}^{DS}	Load shed in demand unit j (MW)
P_{in}^{GC}	Power curtailed in generation unit i (MW)
f_l	Power flow in line l (MW)
$\mathrm{P}_{n:1}^{IMP}$	Power imported from transmission network (MW)

E. Integer variables

TC_{tr}^{BAU}	Number of blocks of transformer tr in *BAU*
LC_{l}^{BAU}	Number of blocks of line l in *BAU*
TC_{tr}^{M}	Number of blocks of Transformer tr in *market case*
LC_{l}^{M}	Number of blocks of line l in *market case*

I. INTRODUCTION

RECENT advances in the introduction of Distributed Energy Resources (DERs), including large renewable and small scale generation, as well as demand-side response, electric vehicles and batteries, have motivated a growing interest in market-based solutions for the provision of energy and flexibility services at a local level. This represents a new competitive tier in the already complex market arrangements of electricity production and retailing. It opens new opportunities of engagement for producers, consumers, retailers, aggregators and network service operators.

Within network operations in particular, the amount of DERs connected at low-voltage levels is creating major disruptions [1]. For the Transmission System Operator (TSO), DERs increase the sources of ancillary service providers, but also bring greater uncertainty to the extent that DER activities may be less visible and predictable closer to real-time operations. For Distribution Network Operators (DNOs), whilst embedded generators present new stresses on the local infrastructure, they also offer a range of active, flexible options to manage their networks. Hence, the emergence of Distribution System Operators (DSOs) is beginning to mirror the activities of the TSOs [2]. All of which motivates the need for an efficient market design to support these transactions. Whilst there is much concern within the industry about co-ordination between DSOs and TSOs in the use of DERs, there is an absence of formal research on the topic. This paper therefore addresses this new research requirement.

Within integrated market architectures, the marginal price of balancing the system is reflected in the Locational Marginal Prices (LMPs). These prices are derived from a centralized optimization traditionally carried out at transmission level. However, one view is that the increase of DERs in the distribution grid may require an extension of the formulation to co-optimize both transmission and distribution, resulting in LMPs for transmission and distribution [3]. In contrast to centrally optimized systems, within liberalized, unbundled market designs, the efficiency of the market is determined by competition and market rules [2]. This is the situation in European power markets, where different market settings arise at local levels operated by DSOs in coordination with their TSO. To find efficient co-ordination arrangements, several TSO-DSO market pilots have emerged across Europe, at national level as in GB [4], [5], and at a wider European level with, for example, the SmartNet project designing a future Trans-European Ancillary Services market [6].

In terms of new TSO-DSO market designs, in one of the most practical studies, [7] addressed several key ingredients but disregarded some fundamental aspects including the possibility of cooperative contracts and the potential cross impacts triggered by separately activated resources. We therefore formulate an analysis that specifically considers these aspects. We also extend the market participation to include Retailers. Thus, based upon a GB distribution business framework [8], we simulate (a) separate markets for DSO, TSO and Retailer, (b) co-ordinated Shapley value allocations for TSO and DSO, and (c) a co-ordinated mechanism including Retailers. Two real days of system operations data are used, over which performances are assessed. The main contribution of the results is to show that separate markets and/or the inclusion of the Retailer are not as efficient as a co-ordinated DSO-TSO procurement.

The rest of this paper is organized as follows. Section II presents the different uses of flexibility by participants, their possible cooperative contracts and their operational conflicts. Section III describes the three mechanism designs, followed in Section IV by their respective formulations. Then, the GB market framework is presented in Section V. The results are in Section VI. Finally the main conclusions are summarized in Section VII.

II. Flexibility for market participants

We consider the three stakeholders, TSO, DSO, and Retailer, that act as buyers of flexibility services, potentially competing for the same resources.

A. DSO flexibility

Typically, planning the reinforcement of distribution networks is a multi-year optimization problem that tackles the trade-off between strategic network planning and incremental network reinforcement. With the penetration of substantial DERs, future network requirements become more uncertain and as a consequence there is increasing risk aversion to fixed, physical reinforcements. More attention has therefore been given to planning processes [9], where smart grid strategies are included such as dynamic line rating, quadrature-boosters, static VAr compensators and Active Network Management (ANM) connections [10]. Customers with ANM connection arrangements are subjected to curtailment based upon predefined heuristic rules imposed by the DSO to alleviate congestion [11]. However, a market mechanism to perform the ANM dispatch would be a more efficient solution [12]. A wide range of flexibility contracts can evidently be of value to the DSO and potentially more attractively than long-term physical reinforcements. While exclusive-use flexibility contracts could be the most practical solution for the DSO, the procurement of the resources in a local market with other interested buyers (like the TSO) could improve the total welfare.

B. TSO flexibility

The TSO requirements for flexibility resources include energy balancing actions, which aim to restore the imbalance of the system, and system balancing actions, which solve operational issues, such as congestion and power quality. Thus, the TSOs are willing to access DER capabilities either in real-time through the balancing market [13] or through capacity contracts such as, in GB, the Short Term Operating Reserve (STOR). The STOR service providers are committed to reserve some capacity to be deployed within a time frame of 5-15 minutes and for a maximum duration of 4 hours. In comparison with the European Union for the Coordination of Transmission of Electricity (UCTE) arrangements, STOR is used sometimes as manual Frequency Response (mFRR) and other times as Replacement Reserve (RR), but going forward, GB is in a process of harmonizing reserve and frequency services with the European reserve market projects [14]. The STOR service is provided through option contracts procured ahead in time both from units participating in the balancing market (BM) and from other non-BM units, typically embedded in the distribution network. A new reserve service is being trialed (Demand Turn Up) [15], designed to increase demand-side engagement, and the TSO has indicated an intention to increase the clearing frequency of STOR contracts and to share these resources with other interested buyers [14], [16].

C. Retailer flexibility

In GB, the Retailers are responsible for contracting the required energy to match their customers' demand, and they are subject to imbalance costs for all real-time discrepancies between metered consumption and their contracted positions. The Retailers also pay the Transmission Network Use of System (TNUoS) charges to the high voltage network owners, and the Balancing Services Use of System (BSUoS) charges to the system operator. As for the investment and maintenance costs of the distribution network, these are recovered through the Distribution Use of System (DUoS) charges. The TNUoS charges in particular follow the peak-load pricing principle, being partly based upon the three highest periods of system demand during the year, known as ”triads” [17]. Therefore, they can be mitigated by providing flexibility services that reduce anticipated peak demand, such as demand reduction services or increased output from embedded generation. To predict triads, Retailers generally subscribe to forecasting services offering specific warnings for these events, both day ahead and intra-day [18].

D. Cross impacts from uncoordinated activations

The uncoordinated activation of flexibility actions among System Operators and Retailers are likely to create additional costs, which can jeopardize the benefits of the flexibility market. In what follows, ”turn-down services” (TDS) refer to demand reductions (or generation increases) and vice versa for ”turn-up services” (TUS). The possible cross impacts depending the direction of the service are presented in Table I:

TABLE I
POTENTIAL CROSS IMPACTS

Service ↓ impact on →	TSO	DSO	Supplier
TSO: STOR service		*(TDS)* Congestion created	
DSO: Congestion service	*(TUS)* Reserve activated		*(TUS,TDS)* Imbalances created
Supplier: Triad service		*(TDS)* Congestion created	

- TSO causes congestion in DSO distribution assets. The cost for DSO can be a degradation of DSO assets such as transformers [3], and in the worst case, the curtailment of generation or loads.
- DSO activates a congestion service in the opposite direction to reserve deployed by the TSO, for which the TSO has to activate further reserves.
- DSO actions cause imbalances in the Retailers' BM exposures.
- Retailer activates services and causes congestion in the distribution and/or transmission network.

III. MARKET MECHANISM DESIGNS

As in [7] and [19], this study assumes that the required capacity is fully available within the delivery day. This can be achieved by long term tenders for resource adequacy, but auctions for capacity payments are outside the scope of this paper. We focus our analysis on the short-term coordination of available resources through local flexibility arrangements. Below, we refer to TSO, DSO and Retailers as flexibility buyers and the DERs as sellers. Three design options are analyzed: a sequential procurement, a double-sided auction, and a tailored mechanism.

A sequential procurement is the simplest and closest to current practice. In this design, sequential tender processes are organized by the different buyers to match their disparate decision time-scales. For example, the reserve needs of the TSO become evident within a timeframe of minutes, whilst for the DSO, a congestion-mitigating service could be predicted several hours ahead. As for the Retailers, they are likely to act upon the day-ahead or mid-day forecast warnings on peak prices, and seek to reduce TNUoS exposures accordingly. Evidently, these three separate mechanisms, by construction, cannot take advantage of coordination opportunities, and as a consequence, nor can they extract the full potential of social welfare from flexibility services.

A single double-sided auction can be based upon a trading platform in which all flexibility is cleared in a one shot auction. This platform would be used to determine the allocation and the utilization of each specific flexibility resource. However, whilst there might be efficiency gains by concentrating the liquidity for services, gaming strategies may occur [20], especially if the buyers' valuations are interdependent [21]. For example, a service activated (and therefore paid) by the DSO can be indirectly beneficial for the TSO and/or the Retailer without incurring any costs for them. This could lead to a free-rider strategy where the TSO and Retailer anticipate the DSO's actions for their own benefits.

The drawbacks of a double-sided auction can be overcome by a tailored mechanism reflecting the complex utility functions of the buyers in this problem. But, one shortcoming of a tailored mechanism is that buyers might have to reveal their valuation functions, which may be proprietary in competitive markets. Nevertheless, this could be managed by regulation to the extent that the TSO and DSO are regulated businesses. As a possible mechanism, the Vickrey-Clarke-Groves (VCG) has been widely applied. For example [22] proposes a VCG mechanism for capturing the time value of different frequency services in the utility function of the GB TSO. In a VCG mechanism the pay-off of a buyer is its relative contribution to the total social welfare [21]. This mechanism has the desired properties of truthfulness (i.e. participants are incentivized to submit true valuations) and efficiency (i.e.maximizes social welfare). However, the sum of VCG pay-offs is non-zero (i.e. it is not budget balanced), requiring additional regulation to handle the imbalances. Thus, we look at other budget-balanced mechanisms that still conserve truthfulness but may relax the efficiency. Note that, according to the Green-Laffont-Hurwicz theorem [21], no truthful mechanism is always both efficient and weakly budget balanced. The Shapley value is a solution concept in cooperative game theory in which a buyer's pay-off is its marginal contribution of the total cost of the possible coalitions [21]. This cost distribution is commonly associated with the notion of fairness. In the flexibility platform context, this is translated into a proportional share of cost when two or more buyers benefit from the same service and are willing to pay for it separately. In our proposed mechanisms the Shapely value will be used to determine the pay-offs (i.e. the settlement), while the activation of services will be based upon maximising social welfare.

In summary, the sequential procurement through separate tender processes is the design closer to current practice, but it cannot achieve efficiency in the overall allocation of services. Furthermore, uncoordinated activation actions can result in undesirable cross impacts between buyers. However, it does allow the different participants to optimize their timings for procurements. The single double-sided auction improves the allocation efficiency, and concentrates liquidity. However gaming strategies can jeopardize the market efficiency because of the interdependent valuations of the buyers. Finally, the tailored mechanism can guarantee allocation efficiency and coordination is achieved by considering the cross impacts. For these reasons, the double-sided auction is disregarded for the rest of the study, and the sequential procurement is compared against two Shapley value mechanisms, with and without the inclusion of the Retailer.

IV. Experimental methodology

The proposed mechanisms have been simulated in a stylized manner based on a distribution network from the UK. Two operational case studies are investigated based upon actual system data. The model represents a typical network constrained by both embedded generation and demand, optimized as described below in Section IV-A.

It is important to re-emphasize that the services activated in this study are not energy balancing services, for which a separate BM runs concurrently. Nevertheless, the cost of energy imbalances do come into the calculations below, and in the context of procuring flexibility services, it is assumed that the DSO and Retailers are price takers with respect to the system price [23]. The modeling proceeds as follows. First the reinforcement level of the distribution network is calculated as baseline. Then, a variety of mathematical formulations to define the dispatch of the mechanisms are presented. Finally, a set of real days, with actual operations, are chosen upon which the dispatch and settlement for the different designs are compared.

A. Reinforcement Cost Calculation

Two levels of reinforcement are defined: traditional incremental network reinforcement (without any use of flexibility services) and reinforcement considering flexibility market arrangements. The first is the base case, being the business as usual (BAU) DNO model, and it will be used to benchmark the valuation of the DSO market-based alternatives. For simplicity of research focus we make the following simplifications: 1) the reinforcement level is assumed to be adjusted to a static distribution network setting under average demand and generation and without multi-year variations; 2) the expected flexibility volume and prices are known in advance in the planning decision; 3) only thermal constraints trigger the reinforcement decisions; 4) the reinforcement costs are modeled in blocks of discrete capacity for lines and transformers and economies of scale are not considered; 5) the power flow is simplified to the linear DC Optimal Power Flow formulation (1). The linearization of power flow equations is subject to the assumptions of negligible losses, small resistance compared to reactance in the lines, and small voltage variation between buses.

$$\begin{aligned} \mathrm{f}_{lt} &= B_l\ (\theta_{nt} - \theta_{mt}), && \forall l=(n,m),t \\ \theta_{nt} &= 0, && n=1 \end{aligned} \tag{1}$$

It is noteworthy that this stylization of the planning decision whilst simplifying is nevertheless sufficient to exemplify the DSO's decision process and characterize a generic distribution network suitable to compare the different mechanisms. The reinforcement decision is formulated as Mixed Integer Linear Programming (MILP), where the new capacity installed of lines and transformers are integer variables ($\mathrm{TC}_{tr}^{BAU}, \mathrm{LC}_l^{BAU}$) multiplied by their respective block size (x^L, x^{TR}). The objective function of the DSO is minimizing the reinforcement cost:

$$Min_{\mathrm{TC}^{BAU},\mathrm{LC}^{BAU}} \sum_{tr} \mathrm{TC}_{tr}^{BAU} x^{TR} C_{tr}^{TR} + \sum_{l} \mathrm{LC}_l^{BAU} x^L C_l^L \tag{2}$$

subject to (1), flow balance constraints (3), transformer and line flow limit constraints (4),(5), and integer variables constraints (6):

$$\begin{aligned} &\sum_{l=(n,m)} \mathrm{f}_{lt} - \sum_{l=(m,n)} \mathrm{f}_{lt} + \sum_{i} P_{int}^{G} \\ &- \sum_{j} P_{jnt}^{D} + \mathrm{P}_{n:1}^{IMP} = 0, \quad \forall n,t \end{aligned} \tag{3}$$

$$\left| \sum_{l=(n,m)} \mathrm{f}_{lt} - \sum_{l=(m,n)} \mathrm{f}_{lt} \right| \le \mathrm{TC}_{tr}^{BAU} x^{TR}, \quad \forall tr,n,t \tag{4}$$

$$|\mathrm{f}_{lt}| \le \mathrm{LC}_l^{BAU} x^L, \quad \forall l,t \tag{5}$$

$$\mathrm{LC}_l^{BAU} \in \mathbb{Z}^+ \quad \forall l, \quad \mathrm{TC}_{tr}^{BAU} \in \mathbb{Z}^+ \quad \forall tr \tag{6}$$

In contrast, with a flexibility market, the DSO optimizes the reinforcement planning decision together with the flexibility services available in the market ($\mathrm{F}_{ut}^{UP}, \mathrm{F}_{dt}^{DW}$):

$$\begin{aligned} &Min_{\mathrm{TC}^M,\mathrm{LC}^M,\mathrm{F}_{ut}^{UP},\mathrm{F}_{dt}^{DW}} \quad \sum_{u} \mathrm{F}_{ut}^{UP}\ \pi_{ut}^{UP} + \sum_{d} \mathrm{F}_{dt}^{DW}\ \pi_{dt}^{dp} \\ &+ \sum_{tr} \mathrm{TC}_{tr}^{M} x^{TR} C_{tr}^{TR} + \sum_{l} \mathrm{LC}_l^{M} x^{TR} C_l^L \end{aligned} \tag{7}$$

subject to (1), flow balance constraints (8), transformer and line flow limit constraints (9),(10), integer variables constraints

(11) and upper and lower bounds of the flexibility bids volume (12),(13):

$$\sum_{l=(n,m)} \mathrm{f}_{lt} - \sum_{l=(m,n)} \mathrm{f}_{lt} + \sum_{i} P^{G}_{int} - \sum_{j} P^{D}_{jnt} + \sum_{u} \mathrm{F}^{UP}_{unt} - \sum_{d} \mathrm{F}^{DW}_{dnt} + \mathrm{P}^{IMP}_{n:1} = 0, \quad \forall n, t \tag{8}$$

$$\left| \sum_{l=(n,m)} \mathrm{f}_{lt} - \sum_{l=(m,n)} \mathrm{f}_{lt} \right| \leq \mathrm{TC}^{M}_{tr} x^{TR}, \quad \forall tr, n, t \tag{9}$$

$$|\mathrm{f}_{lt}| \leq \mathrm{LC}^{M}_{l} x^{L}, \quad \forall l, t \tag{10}$$

$$\mathrm{LC}^{M}_{l} \in \mathbb{Z}^{+} \quad \forall l, \quad \mathrm{TC}^{M}_{tr} \in \mathbb{Z}^{+} \tag{11}$$

$$0 \leq \mathrm{F}^{UP}_{ut} \leq F^{UP,max}_{ut} \quad \forall u, t \tag{12}$$

$$0 \leq \mathrm{F}^{DW}_{dt} \leq F^{DW,max}_{dt} \quad \forall d, t \tag{13}$$

Below, ($\mathrm{LC}^{M} x^{L}, \mathrm{TC}^{M} x^{TR}$) define the line and transformer capacity parameters (LC, TC) in the subsequent formulations.

B. Market Designs

Three possible market designs are proposed here: the sequential procurement and two tailored mechanisms. The two tailored mechanisms reflect first the joint procurement of TSO, DSO and Retailer, followed by a separated version where the Retailer procures on its own. In this setting, the exact timings of the activation signals are not crucial, but the order of activation by the buyers is the key aspect. Figure 1 represents a timeline diagram displaying the interests of the buyers, and the procurement process in the three market schemes.

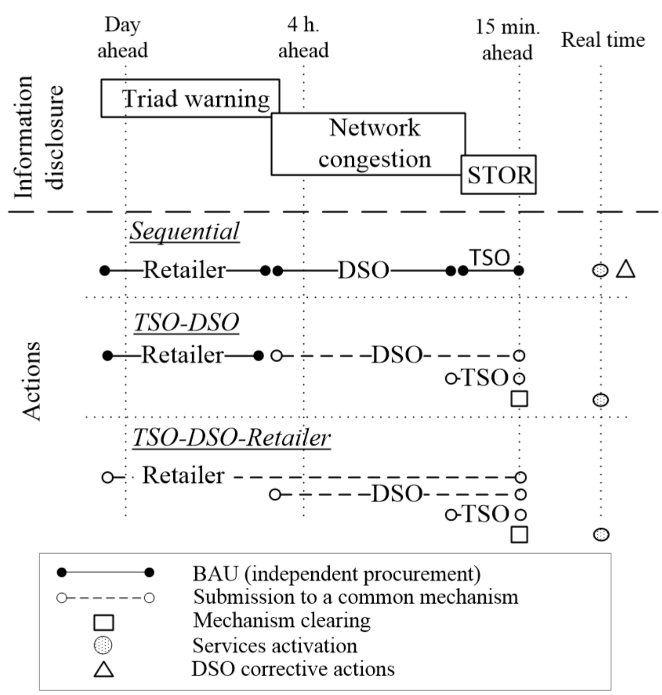

Fig. 1. Coordination timeline diagram.

In all the market designs considered, the sellers (DERs) are settled on a "pay-as-bid" basis, and they are assumed to post their services on to a trading platform where the buyers (or a mechanism) can contract. Furthermore, the services can be accepted fully or in part.

1) Sequential Design: In this scheme the buyers activate services sequentially. First, the Retailer procure TDS (F^{DW}) for the peak price periods if a triad warning event occurs ($t \in T^{triad}$). For its problem, a Retailer minimizes the price difference between the flexibility service and the expected TNUoS cost in its objective function (OF):

$$Min_{\mathrm{F}^{DW}_{dt}} OF^{RET} = \sum_{t \in T^{TW}} \sum_{d} \mathrm{F}^{DW}_{dt} (\pi^{DW}_{dt} - \hat{P}^{T}_{t} \hat{C}^{TNUoS}) \tag{14}$$

$$Subject\ to: (12), (13)$$

Then, the flexibility TDS (F^{DW}) acquired by the Retailer is removed from set of services available to DSO, as the volumes already committed to the Retailer are no longer available for subsequent procurement. The DSO requires both TUS, to solve congestion caused by generators, and TDS to solve congestion caused by demand. The problem for the DSO is to minimize the payments to the flexibility providers while respecting the thermal limits of the network:

$$Min_{\mathrm{F}^{UP}_{ut}, \mathrm{F}^{DW}_{dt}} \quad OF^{DSO} = \tag{15}$$

$$\sum_{t} \sum_{d} \mathrm{F}^{DW}_{dt} \pi^{DW}_{dt} + \sum_{t} \sum_{u} \mathrm{F}^{UP}_{ut} \pi^{UP}_{ut} \tag{16}$$

$$Subject\ to: (1), (8), (12), (13), \tag{17}$$

$$\left| \sum_{l=(n,m)} \mathrm{f}_{lt} - \sum_{l=(m,n)} \mathrm{f}_{lt} \right| \leq TC_{tr}, \quad \forall tr, n, t \tag{18}$$

$$|\mathrm{f}_{lt}| \leq LC_{l}, \quad \forall l, t \tag{19}$$

We do not consider the alternative sequence in which the DSO commits ahead of the Retailer. Given that the Retailer is procuring flexibility on the basis of day ahead peak load warnings, the DSO will be aware of this and will need to respond accordingly to the Retailer's activations. Further, as more active intra-day condition monitoring is introduced, (e.g. dynamic line rating), the DSO procurement is likely to become closer to real-time. After the DSO procurement, the services ($\mathrm{F}^{UP}, \mathrm{F}^{DW}$) acquired by the DSO are removed from the set of services available to the TSO. The TSO bases its procurement decision on the difference between the activation prices of down reserves (STOR) (π^{RD}) and the flexibility price (π^{UP}):

$$Min_{\mathrm{F}^{DW}_{dt}} \quad OF^{TSO} = \sum_{t \in T^{RD}} \sum_{d} \mathrm{F}^{DW}_{dt} (\pi^{DW}_{dt} - \pi^{RD}_{t}) \tag{20}$$

$$Subject\ to: (12), (13) \tag{21}$$

Insofar as TSO modifies the previous DSO security constrained dispatch, the DSO has to correct the contingencies by curtailing load and/or generation in real-time:

$$Min_{\mathrm{P}_{it}^{GC},\mathrm{P}_{jt}^{DS}} \quad OF^{DSO-RT} = \tag{22}$$
$$\sum_t \sum_i VOLG\ \mathrm{P}_{it}^{GC} + \sum_t \sum_j VOLL\ \mathrm{P}_{jt}^{DS} \tag{23}$$
$$Subject\ to: \tag{24}$$
$$\sum_l \mathrm{f}_{lt} + \sum_i (P_{int}^{G} - \mathrm{P}_{int}^{GC}) \tag{25}$$
$$-\sum_j (P_{jnt}^{D} - \mathrm{P}_{jnt}^{DS}) + \sum_u \mathrm{F}_{unt}^{UP} \tag{26}$$
$$-\sum_d \mathrm{F}_{dnt}^{DW} = 0, \quad \forall n,t \tag{27}$$

As for the valuation of each buyer, the DSO considers the savings in reinforcement costs amortized over the hours of services called. As for the Retailer, the valuation is the savings of TNUoS payments ($\mathrm{F}^{DW}\hat{P}_t^T\hat{C}^{TNUoS}$) in the case a peak load event occurs. For the TSO, the valuation is the savings on activation payments of STOR contracts ($\mathrm{F}^{DW}\pi^{RD}$). These definitions of the valuations remain the same for the other two mechanisms.

2) TSO-DSO mechanism: The TSO and DSO are regulated entities, whereas the Retailer is a private company looking to maximize its profit. Hence, we first consider a semi-separate market where Retailer firstly procures TDS for peak-load avoidance services. As in the sequential procurement, Retailer procures its services according to (14). Then, the units contracted by the retailer are removed from the set of services available to the mechanism. Following the sequence of Figure 1, the DSO and TSO send their valuations and constraints to this co-ordination mechanism, which, 15 minutes ahead of delivery, performs a market clearing that maximizes the total welfare of both buyers. The formulation of the TSO-DSO mechanism includes the DSO's power flow and balance constraints (1),(8),(12),(13) and the flexibility units availability constraints (18),(19). While the objective function minimizes the procurement cost of TUS and TDS, considering the valuation of TSO's reserves contracts ($\mathrm{F}^{DW}\pi^{RD}$) and the cost of TSO's cross impacts due to services activated in opposite direction ($\mathrm{F}^{UP}\pi^{RD}$):

$$Min_{\mathrm{F}_{ut}^{UP},\mathrm{F}_{dt}^{DW}} \quad OF^{TSO-DSO} = \tag{28}$$
$$\sum_t \sum_u \mathrm{F}_{ut}^{UP}\ \pi_{ut}^{UP} + \sum_t \sum_d \mathrm{F}_{dt}^{DW}\ \pi_{dt}^{DW} \tag{29}$$
$$+ \sum_{t\in T^{RD}} \sum_u \mathrm{F}_{ut}^{UP}\pi_t^{RD} - \sum_{t\in T^{RD}} \sum_d \mathrm{F}_{dt}^{DW}\ \pi_t^{RD} \tag{30}$$
$$Subject\ to: (1),(8),(12),(13),(18),(19) \tag{31}$$

In the TSO-DSO and TSO-DSO-Retailer mechanisms the DSO valuation is included in the last decision (i.e. mechanism clearing) before delivery, hence the DSO does not have to adopt post-mechanism actions as the mechanism itself ensures the dispatch feasibility for the DSO.

3) TSO-DSO-Retailer mechanism: This mechanism integrates the three buyers. The constraints of the mechanism clearing problem are the same than for the TSO-DSO mechanism, and the objective function is modified to include the valuation of Retailer ($\mathrm{F}^{DW}\hat{P}_t^T\hat{C}^{TNUoS}$):

$$Min_{\mathrm{F}_{ut}^{UP},\mathrm{F}_{dt}^{DW}} \quad OF^{TSO-DSO-Ret} = \tag{32}$$
$$\sum_t \sum_u \mathrm{F}_{ut}^{UP}\ \pi_{ut}^{UP} + \sum_t \sum_d \mathrm{F}_{dt}^{DW}\ \pi_{dt}^{DW} \tag{33}$$
$$+ \sum_{t\in T^{RD}} \sum_u \mathrm{F}_{ut}^{UP}\pi_t^{RD} - \sum_{t\in T^{RD}} \sum_d \mathrm{F}_{dt}^{DW}\ \pi_t^{RD} \tag{34}$$
$$- \sum_{t\in T^{triad}} \mathrm{F}_{dt}^{DW}\ \hat{P}_t^T\hat{C}^{TNUoS} \tag{35}$$
$$Subject\ to: (1),(8),(12),(13),(18),(19) \tag{36}$$

C. Mechanism settlements

In the sequential mechanism, the settlement consists of a payment for the services activated by each buyer based upon a "pay-as-bid" basis. For the other two mechanisms, an additional procedure is used to compute the Shapley value payoffs for each buyer. Recalling from Section III, the cost of a service should be shared only between the buyers that would procure the service separately. Therefore, we define "flexibility interest" as the volume of these services for each interested buyer. The settlement calculation for the tailored mechanisms consists of three steps:

- *Mechanism clearing*: Solving (30) for the TSO-DSO mechanism or (35) for the TSO-DSO-Retailer mechanism. The cost of each service is the volume activated multiplied by the bid price for each service.
- *Calculation of flexibility interests*: These are determined solving (14) for Retailer, (16) for DSO, and (20) for TSO.
- *Shapley value settlement*: The costs of each service are divided pro rata over the flexibility interests of all the buyers.

Regarding energy imbalance settlements, in the sequential procurement, the Retailer imbalances are settled according to the prevailing Balancing & Settlement Code rules, which do not consider volumes activated by DSOs. Therefore this can result in the undesired cross impact shown in Table I. This consideration has been included in the settlement of the tailored mechanisms, as the TSO (who is responsible for balancing the system) accounts for the volume activated within the mechanism and does not charge the Retailer for it. Table II summarizes the dispatch function, services settlement, imbalances settlement and cross impacts for each mechanism.

V. Application

A. Description

The experimental network in Figure 2 has the topology of a real 33 kV distribution network in a rural area in the UK, which is connected directly to the transmission network at 132 kV. The loads and generators data are presented in Table III. The demand and generation profiles are shown in Figure 3, reflecting a typical winter day of peak generation. The inputs P_{jn}^D and P_{in}^G are obtained multiplying the values of Table III by the profiles in Figure 3. Note that this mix of demand and generation is not rare in current UK distribution

TABLE II
RESUME OF THE THREE MECHANISM DESIGN OPTIONS

	Dispatch function	Imbalance Settlement rules	Services Settlement rules	Cross impacts
Sequential mechanism	Valuation of each party on its market	Balancing & Settlement Code rules	Each party pays for its services	Retailer pays imbalances generated by DSO, DSO pays RT adjustments, TSO pays further reserve deployed
Retailer + TSO-DSO mechanism	Retailer valuation in its market, TSO + DSO valuations in the joint market	BSC rules for Retailer , New rules for DSO: DSO pays its imbalances	Retailer pays its services, DSO and TSO share the cost of co-ordinated services.	-
TSO-DSO-Retailer mechanism	Joint valuation of TSO+DSO+Retailer	New rules for everyone: DSO and Retailer pay their imbalances	Everyone shares the cost of co-ordinated services.	-

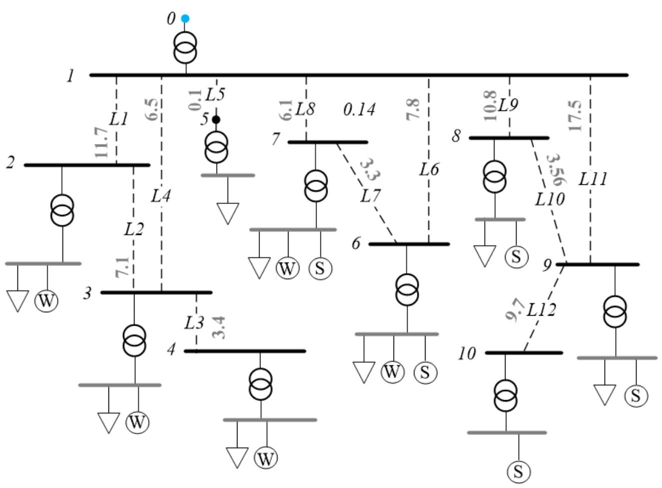

Fig. 2. Distribution network of the case study.The lengths of the lines (km) appear in grey. Node 0: 132 kV, black: 33 kV, grey: 11 kV. S: Solar generator, W: wind generator.

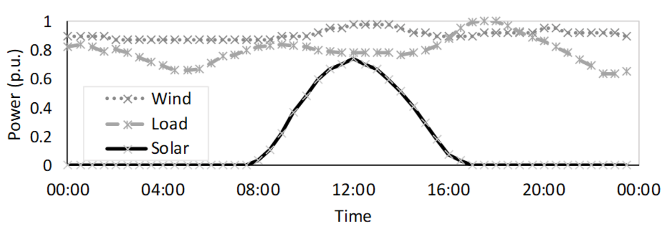

Fig. 3. Profiles used in the case study.

networks. The reinforcement level with the flexibility market has been obtained as explained in Section IV-A, and the results are presented in Table IV. For this small stylized system, the annualized cost of the BAU case is £1.411M, whereas in the market case it is £1.288 M, of which £32,000 is the cost of the services procured by DSO. For this specification, an average annualized cost of £200/MW/km has been assumed for lines and £2,000/MW for transformers. The line impedances have been obtained from [10]. Also, an average requirement for 10 days of flexibility services in the year has been assumed. This is a typical but arbitrary value and does not affect the comparative nature of our results.

The embedded generators are assumed to bid all their capacity for TUS at the price of the subsidy they are receiving (e.g. Feed-in-Tariff). The loads, on the other hand, are assumed to have 10% of their consumption flexible, for example by electric vehicle charge management, demand reduction or embedded storage systems. This flexibility can materialize either as a TUS or TDS throughout the day. The detailed information of the size and pricing used can be found in Table

TABLE III
LOAD AND GENERATORS DATA USED IN THE CASE STUDIES

Load id.	Node ID	Av. power (MW)	Turn Up bid (£/MWh)	Turn Down bid (£/MWh)
Load 1	2	29	12.6	22.6
Load 2	3	35	15.1	25.1
Load 3	4	33	11.9	21.9
Load 4	5	19	16.4	26.4
Load 5	6	50	16.7	26.7
Load 6	7	16	16.2	26.2
Load 7	8	46	16.7	26.7
Load 8	9	50	10.8	20.8
Gen. id.	**Node ID**	**Capacity (MW)**	**Turn Up bid (£/MWh)**	
Solar 1	6	10	45.3	
Solar 2	7	17	43.6	
Solar 3	8	14	39.5	
Solar 4	9	42	34.6	
Solar 5	10	23	57.8	
Wind 1	2	22	55.5	
Wind 2	3	25	32.9	
Wind 3	4	14	44.6	
Wind 4	6	27	53.4	
Wind 5	7	46	43.6	

TABLE IV
NETWORK CAPACITY: BAU AND WITH MARKET ARRANGEMENTS

Line	BAU (MW)	Market (MW)	Transf. (node)	BAU (MW)	Market (MW)
L1	20	10	0	160	130
L2	10	*	2	10	*
L3	30	20	3	20	10
L4	30	*	4	30	20
L5	20	*	5	20	*
L6	20	*	6	30	*
L7	30	*	7	50	40
L8	30	20	8	50	*
L9	60	*	9	50	*
L10	20	*	10	20	*
L11	40	*			
L12	20	*			

**same values as BAU*

III. Finally, a Value of Lost Load (VOLL) of £6,000/MWh and a Value of Lost Generation (VOLG) of £100/MWh have been assumed.

B. Case studies

Creating model-based insights on the relative performance of the three co-ordination mechanisms presented a modeling challenge. Whilst the local network specified above is sufficiently realistic to represent and evaluate the DSO requirements for flexibility services, the TSO requirements for STOR and the Retailer's behavior in relation to "triad" (peak load) warnings cannot emerge endogenously within that model, as their occurrences are a result of national wholesale market circumstances. Furthermore these circumstances are infrequent and require very extensive detail to model. We therefore needed to realistically map exogenous STOR and triad events on to our simulated local network model. Looking at actual daily case studies to make use of their operational data as inputs to our local area model, we carefully selected case studies from the winter season, when peak demand may cause local congestion, the TSO may require STOR and triad warning events usually happen. But looking at the historical data, STOR and triad events did not tend to co-exist as the triad warning response by Retailers preclude the need for STOR. Thus, the case studies of interest were adequately represented by two operational days: a day in which STOR overlapped during morning and afternoon with DSO services and a day in which STOR did not overlap with DSO services but Retailer responses to triad warning did interact with DSO requirements. Note that in reality it is very unlikely that any other operational situation with concurrency between buyers procurements could occur. For example, it is unlikely that a DSO would experience thermal congestion in its assets due to excessive demand outside the typical peak demand period as well as congestion due to excessive generation outside the typical peak generation period. Each case study used the actual data of system price, volume of STOR deployed and price of the most expensive unit activated. The STOR data was dispatched outside the balancing mechanism and was provided by the settlement agency in GB, Elexon [24]. The detailed information of system operation was taken from National Grid website [25]. The days are:

- Case study 1: Saturday 13th of January of 2018: STOR instructed during the morning coincided with the peak hour of generation in the distribution network, and in the afternoon during the peak hour of demand in the distribution network.
- Case study 2: Monday 15th of January of 2018: STOR was dispatched during the morning, whereas the facilities held for the afternoon were not activated. This was attributed to 2,000 MW of demand response encouraged by a peak warning event to the Retailers.

Thus, case study 2 represents a day of activity by the Retailer and its results are used to compare the performance of TSO-DSO-Retailer scheme against the TSO-DSO one. On the other hand, in case study 1, the services of TSO and DSO interact.

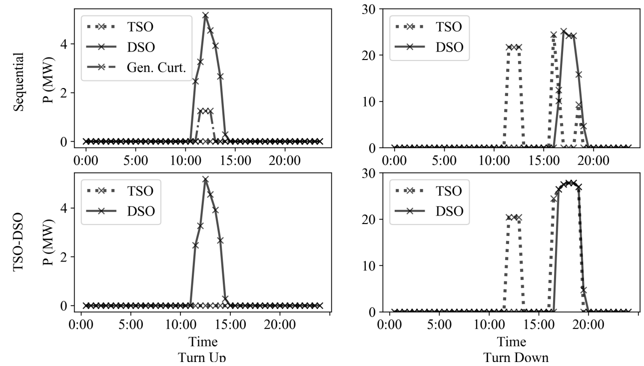

Fig. 4. Results of the flexibility dispatched intra-day. Case study 1.

TABLE V
SEQUENTIAL AND TSO-DSO MECHANISMS RESULTS IN CASE STUDY 1

		Sequential	TSO−DSO
DSO	Valuation (£)	13,027	13,027
	Cost (£)	-1,606	-1,262
	Cross Impact (£)	-187	-
	Welfare (£)	11,234	11,765
TSO	Valuation (£)	6,051	17,204
	Cost (£)	-1,381	-1,875
	Cross Impact (£)	-844	-
	Welfare (£)	3825	15,329
Retailer	Valuation (£)	-	-
	Cost (£)	-	-
	Cross Impact (£))	6,994	-
	Welfare (£)	6,994	-
Totals	Welfare (£)	22,053	27,094

Hence, they are used to compare the benefits of the TSO-DSO scheme against the sequential procurement.

The two case studies are analyzed using a set of metrics based upon the valuations, cost of services and cost cross impacts for each buyer. In addition, the welfare is defined as the valuation minus these costs. These metrics are used to evaluate the profits of the cooperative contracts, and the costs incurred by the cross impacts. The intra-day co-ordination is depicted below by graphs of the flexibility activated by each buyer.

VI. RESULTS

A. Case study 1: STOR deployed during DSO congestion services

In case study 1, the STOR deployed by National Grid coincides with the flexibility services needed from the DSO for congestion management. During this day no peak price warning was issued, so the Retailer does not participate in the market.

Figure 4 depicts the intra-day services activated by DSO and TSO, differentiated between mechanism and direction of the service (TUS or TDS), whereas Table V presents the breakdown of each buyer's welfare according to the metrics defined in Section V-B. In the upper right quadrant of Figure 4 (sequential mechanism), the TSO activates 21 MW of TDS at midday, for which the DSO has to curtail 1 MW of generation

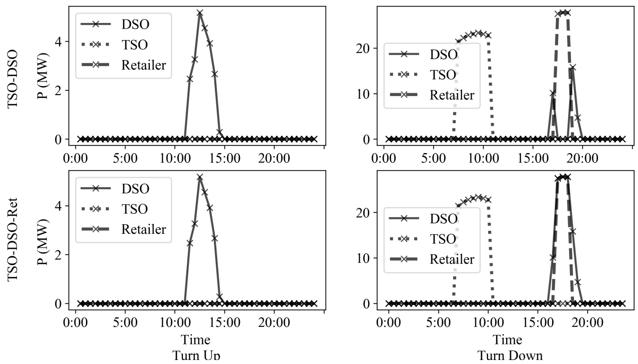

Fig. 5. Results of the flexibility dispatched intra-day. Case study 2.

TABLE VI
MECHANISMS RESULTS IN CASE STUDY 2

		Sequential	**TSO-DSO-Ret**	**TSO-DSO**
DSO	Valuation (£)	13,027	13,027	13,027
	Cost (£)	-721	-1,228	-721
	Cross Impact (£)	-	-	-
	Welfare (£)	12,307	11,800	12,307
TSO	Valuation (£)	18,131	18,131	18,131
	Cost (£)	-1,936	-1,936	-1,936
	Cross Impact (£)	-	-	-
	Welfare (£)	16,195	16,195	16,195
Retailer	Valuation (£)	550,440	550,440	550,440
	Cost (£)	-1,014	-507	-1,014
	Cross Impact (£)	488	-	-
	Welfare (£)	549,914	549,933	549,426
Totals	Welfare (£)	578,416	577,928	577,928

(upper left quadrant, Figure 4). Recalling from Section II-D, the uncoordinated activation of TDS by TSO can force the DSO to carry out generation curtailment actions. This is reflected in a cross impact in Table V of £187 incurred by the DSO, and £844 by the TSO for having to pay additional STOR units (as the DSO nets off TSO's services). The second insight of Figure 4 comes from the upper right quadrant, where the TSO is not able to procure any TDS between 17:00 and 18:00 because of the previous DSO TDS acquisitions. On the contrary, in the lower right quadrant (TSO-DSO mechanism), both buyers account for the same TDS service at that time. The gains of this collaborative contract are reflected in Table V, where the DSO reduces its total procurement costs by 21.4%, and the TSO increases its valuation by 184.3%. The third key aspect of the sequential mechanism is reflected in the Retailer row in Table V, with a cross impact profit of £6,994. Such cross impact is the result of a net negative imbalance caused by the DSO that is inflicted upon Retailer as in Table I. In this case, the cross impact is reflected into a profit because the Retailer has a long position from the system perspective (consumes less than contracted), therefore the net deviation is compensated at the balancing price (in this instance being positive). Despite having a positive contribution to the welfare shown in Table V, such a cross impact is undesirable as it is an unintended consequence. Regarding the type of flexibility services, the demand-response units are procured before the generation units because of their offer prices, with only 4 MW of TUS provided by the solar unit in node 7 around midday.

B. Case study 2: Peak load warning event

The 15th of January of 2018 was characterized by a strong demand response due to a peak load warning event ($\hat{P}^T = 1$). As in Case study 1, Table VI and Figure 5 are used to illustrate the outcomes of the mechanisms.

The Sequential mechanism has not been included in Figure 5 as the flexibility dispatch is the same as in TSO-DSO procurements. This is because the TSO and DSO service interests do not coincide in time. The only difference in Figure 5 is found between the dispatch of TDS in the upper right quadrant, where the Retailer procures TDS alone between 17:00 and 18:00, and in the lower right quadrant where the DSO and the Retailer procure the same services jointly. Such a difference is due to an alignment of their procurement needs in the TSO-DSO-Retailer mechanism (lower right quadrant), whereas in the sequential mechanism Retailer relieves indirectly the needs for TDS by DSO. The TSO services are limited to TDS activation during the STOR morning window. The afternoon does not require any STOR because the peak load demand management relieves the reserve needs, therefore a conflict between Retailer and TSO procurement is very unlikely to happen. As seen in Table VI, the Retailer incurs entirely the cost of the TDS procured in the TSO-DSO mechanism, whereas the DSO and the Retailer share that cost in the TSO-DSO-Retailer mechanism. The result of the TSO-DSO-Retailer scheme suggests that some of the Retailer's costs will be incurred by the DSO, which will then be socialized among all the distribution users. Such undesired effects and the apparent absence of improvement in social welfare weaken the interest in implementing this scheme. Moreover, as in Case study 1, the Retailer profits from the cross impacts caused by DSO imbalances in the Sequential mechanism.

In summary, Case study 1 reflects an important improvement of the DSO and TSO welfare in the TSO-DSO mechanism over the sequential procurement due to a share of cost in the evening TDS and the avoided cross impact cost in the midday TUS. Both case studies reflect the undesired cross impacts on the Retailer. Finally, the inclusion of the Retailer in the TSO-DSO-Retailer mechanism creates an undesirable transfer of costs from the Retailer to the DSO in Case study 2. Therefore the co-ordinated TSO-DSO mechanism is found to be the preferable choice.

VII. CONCLUSION

This paper proposes three types of market designs to activate flexibility services embedded in the distribution network. The flexibility is used by the TSO for operating reserve deployment, by the DSO for congestion services, and by Retailers to set against peak-load network tariffs. For two selected case study days in the British power system, simulating these market designs revealed that the co-ordinated TSO-DSO mechanism substantially increases the welfare of system operators compared to the separate sequential mechanism. The inclusion of the Retailer in the joint dispatch does not increase the total welfare. Thus, the analysis of two actual operational days with a realistic model of local area congestion provides persuasive and intuitive evidence to suggest that the most effective co-ordination would be regulated co-operative dispatch between network and system operators, and a separate competitive market for Retailers. The results discussed represent the operation of the British power system and are therefore idiosyncratic in some of the operational details, but the general principles could apply to other power markets exhibiting similar business features among Retailers, DSOs and TSOs. Furthermore, this formulation could be extended to model other operations of DSOs, such as voltage management, fault recovery, or island operation. As for the TSO, the model could be extended to include interests in other ancillary services, such as frequency response, or congestion management in the transmission network.

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